I. Strategist Modeling Assumptions

1. Discount Rate and Capital Structure

The discount rate used for levelized cost calculations and the present value of modeled costs is 6.30 percent. The rates shown in Table 1 were calculated by taking a weighted average of NSP jurisdictions from the June 2017 Corporate Assumptions Memo.

Table 1: Capital Structure

	Capital Structure	Allowed Return	Before Tax Electric WACC	After Tax Electric WACC
Long-Term Debt	45.60%	4.87%	2.22%	1.32%
Common Equity	52.50%	9.39%	4.93%	4.93%
Short-Term Debt	1.90%	2.85%	0.05%	0.05%
Total			**7.20%**	**6.30%**

2. Inflation Rates

The inflation rates are used for existing resources, generic resources, and other costs related to general inflationary trends in the modeling. The inflation rates are developed using long-term forecasts from Global Insight. The labor and non-labor inflation rates are from the February 2016 Corporate Assumptions Memo. The General inflation rate is from the "Chained Price Index for Total Personal Consumption Expenditures" published in the third quarter of 2015.

- Variable O&M inflation – 50% labor inflation and 50% non-labor inflation – 2.88%.
- Fixed O&M inflation – 75% labor inflation and 25% non-labor inflation – 3.07%.
- General inflation – The inflation rate used for construction (capital) costs and any other escalation factor related to general inflationary trends is 2.0%.

3. Reserve Margin

The reserve margin at the time of MISO's peak is 7.8 percent. The coincidence factor between the NSP System and MISO system peak is 5 percent. Therefore, the effective reserve margin is:

$$(1 - 5\%) * (1 + 7.8\%) - 1 = 2.41\%.$$

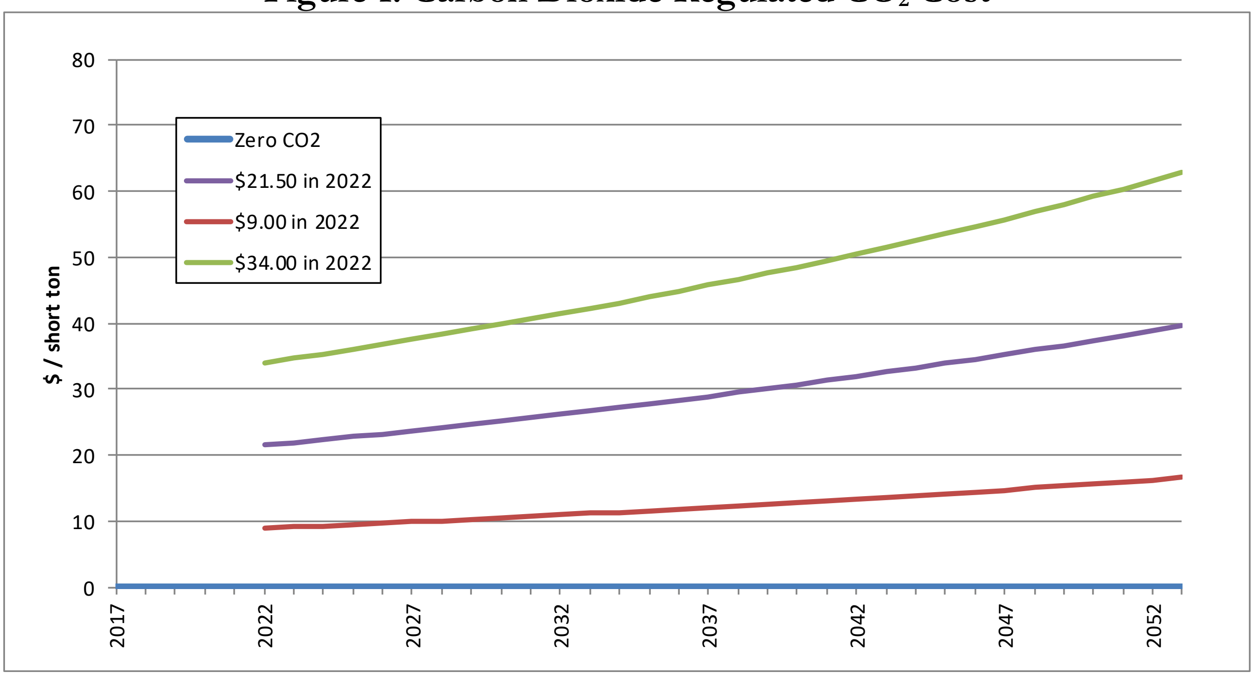
Table 2: Reserve Margin

Reserve Margin	
Coincidence Factor	5.00%
MISO Coincident Peak Reserve Margin %	7.80%
Effective RM Based on Non-coincident Peak	2.41%

4. Regulated CO_2 Costs

Figure 1 shows the annual Regulated CO_2 Costs used in the analysis. The base assumption is $21.50 per short ton starting in 2022 which is the average of $9 per short ton and $34 per short ton. The range of Regulated CO_2 Costs is drawn from the Minnesota Public Utilities Commission's Order Establishing 2016 and 2017 Estimate of Future Carbon Dioxide Regulation Costs in Docket No. E999/CI-07-1199 issued August 5, 2016. All prices escalate at general inflation.

Figure 1: Carbon Dioxide Regulated CO_2 Cost



5. Externality Costs

Externality Costs for NOx, PM10, CO, and Pb are based on the high values from the Minnesota Public Utilities Commission's Notice of Comment Period on Updated Environmental Externality Values issued June 16, 2016 (Docket Nos. E999/CI-93-583 and E999/CI-00-1636) and are shown in Table 3 below. Prices are shown in 2016 dollars and escalate at general inflation. Sulfur dioxide assumed zero cost due to a large surplus of allowances, a weak sales market, and zero externality cost per Commission policy.

Table 3: Externality Costs

MPUC Externality Costs				
$2016 per short ton				
	Urban	**Metro Fringe**	**Rural**	**<200mi**
NOx	$1,466	$399	$153	$153
PM10	$9,627	$4,326	$1,282	$1,282
CO	$3	$2	$1	$1
Pb	$5,808	$2,990	$671	$671

Externality Costs for CO_2 are based on the low and high values from MPUC Docket No. E999-CI-14-643, Fourth Affidavit of Anne E. Smith, Ph.D., Table B. These values in nominal dollars are shown in Table 4.

Table 4: Carbon Dioxide Externality Costs

MPUC CO_2 Externality Costs		
$ per short ton		
Year	Low	High
2017	8.78	41.37
2018	9.17	43.15
2019	9.58	44.99
2020	9.99	46.88
2021	10.42	48.83
2022	10.87	50.84
2023	11.32	52.91
2024	11.80	55.05
2025	12.28	57.24
2026	12.78	59.51
2027	13.29	61.85
2028	13.83	64.25
2029	14.37	66.73
2030	14.94	69.27
2031	15.51	71.89
2032	16.12	74.59
2033	16.72	77.37
2034	17.37	80.23
2035	18.01	83.17
2036	18.69	86.20
2037	19.37	89.31
2038	20.09	92.52
2039	20.81	95.83
2040	21.57	99.22
2041	22.34	102.71
2042	23.15	106.30
2043	23.96	110.00
2044	24.81	113.80
2045	25.67	117.70
2046	26.57	121.72
2047	27.48	125.85
2048	28.43	130.10
2049	29.39	134.46
2050	30.40	138.95
2051	31.42	143.58
2052	32.47	148.32
2053	33.56	153.20

6. Demand and Energy Forecast

The Spring 2017 Load Forecast developed by the Xcel Energy Load Forecasting group is used.

Table 5: Spring 2017 Demand and Energy Forecast

Demand (MW)				Energy (GWh)			
Year	Model Output	W/ Hist DSM, Building Code Adj	Final w DSM/Eff Adjustments	Year	Model Output	W/ Hist DSM, Building Code	Final w DSM/Eff Adjustments
2017	10,435	9,293	9,202	2017	50,828	44,965	44,526
2018	10,485	9,401	9,221	2018	50,739	45,279	44,400
2019	10,559	9,535	9,263	2019	51,173	45,957	44,639
2020	10,646	9,652	9,309	2020	51,485	46,477	44,705
2021	10,726	9,773	9,358	2021	51,715	46,904	44,688
2022	10,815	9,931	9,444	2022	51,912	47,391	44,726
2023	10,911	10,004	9,314	2023	52,217	47,861	44,747
2024	11,013	10,169	9,392	2024	52,566	48,387	44,813
2025	11,123	10,330	9,466	2025	52,831	48,988	44,976
2026	11,239	10,504	9,553	2026	52,984	49,493	45,032
2027	11,343	10,710	9,672	2027	53,258	50,214	45,304
2028	11,445	10,879	9,754	2028	53,630	51,036	45,662
2029	11,558	10,993	9,781	2029	53,930	51,447	45,639
2030	11,673	11,152	9,853	2030	54,118	51,923	45,666
2031	11,779	11,280	10,008	2031	54,414	52,356	46,090
2032	11,883	11,391	10,146	2032	54,778	52,788	46,493
2033	12,005	11,530	10,312	2033	55,080	53,191	46,905
2034	12,127	11,653	10,435	2034	55,263	53,416	47,130
2035	12,234	11,751	10,534	2035	55,551	53,715	47,429
2036	12,335	11,858	10,640	2036	55,903	54,151	47,846
2037	12,450	11,949	10,732	2037	56,184	54,393	48,106
2038	12,570	12,045	10,828	2038	56,363	54,530	48,244
2039	12,679	12,129	10,911	2039	56,675	54,798	48,512
2040	12,784	12,206	10,989	2040	57,059	55,135	48,830
2041	12,900	12,293	11,075	2041	57,371	55,399	49,113
2042	13,020	12,381	11,164	2042	57,560	55,537	49,251
2043	13,124	12,451	11,234	2043	57,877	55,800	49,514
2044	13,237	12,530	11,313	2044	58,241	56,112	49,807
2045	13,326	12,586	11,368	2045	58,563	56,384	50,098
2046	13,438	12,664	11,447	2046	58,748	56,521	50,235
2047	13,540	12,733	11,515	2047	59,117	56,836	50,550
2048	13,644	12,803	11,585	2048	59,590	57,254	50,950
2049	13,748	12,873	11,655	2049	59,729	57,347	51,061
2050	13,851	12,943	11,726	2050	60,036	57,602	51,316
2051	13,955	13,013	11,796	2051	60,342	57,857	51,567
2052	14,059	13,083	11,866	2052	60,818	58,278	51,969
2053	14,163	13,153	11,936	2053	60,955	58,368	52,078

7. DSM Forecast

The DSM forecast assumes impacts expected at a 75 percent rebate level which equals roughly 1.5 percent of sales through the planning period.

Table 6: DSM Forecast

Year	Energy (MWh)	Demand (MW)
2017	439	113
2018	879	227
2019	1,318	342
2020	1,772	429
2021	2,216	516
2022	2,665	603
2023	3,114	690
2024	3,573	777
2025	4,012	864
2026	4,461	951
2027	4,910	1,038
2028	5,375	1,125
2029	5,808	1,212
2030	6,257	1,299
2031	6,266	1,272
2032	6,294	1,245
2033	6,286	1,217
2034	6,286	1,217
2035	6,286	1,217
2036	6,305	1,217
2037	6,286	1,217
2038	6,286	1,217
2039	6,286	1,217
2040	6,305	1,217
2041	6,286	1,217
2042	6,286	1,217
2043	6,286	1,217
2044	6,305	1,217
2045	6,286	1,217
2046	6,286	1,217
2047	6,286	1,217
2048	6,305	1,217
2049	6,286	1,217
2050	6,286	1,217
2051	6,290	1,217
2052	6,308	1,217
2053	6,290	1,217

8. Demand Response Forecast

The 2017 Load Management Forecast developed by the Xcel Energy Load Research group is used. The table below shows the July demand.

Table 7: 2017 Load Management Forecast

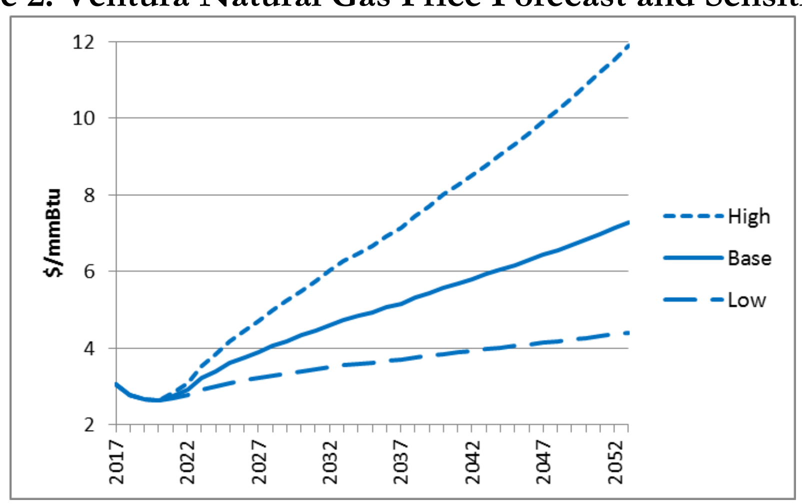
July Demand (MW)	2017	2018	2019	2020	2021	2022	2023	2024
LMF	853	864	880	896	911	926	933	940
July Demand (MW)	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
LMF	947	948	944	940	936	932	928	924
July Demand (MW)	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
LMF	920	916	913	909	905	901	898	894
July Demand (MW)	**2041**	**2042**	**2043**	**2044**	**2045**	**2046**	**2047**	**2048**
LMF	891	887	884	880	877	873	870	866
July Demand (MW)	**2049**	**2050**	**2051**	**2052**	**2053**			
LMF	863	860	856	853	849			

9. Natural Gas Price Forecasts

Henry Hub natural gas prices are developed using a blend of market information (New York Mercantile Exchange futures prices) and long-term fundamentally-based forecasts from Wood Mackenzie, Cambridge Energy Research Associates (CERA) and Petroleum Industry Research Associates (PIRA).

Gas Prices as of February 28, 2017 were used. High and low gas price sensitivities were performed by adjusting the growth rate up and down by 50 percent from the base natural gas cost forecast starting in year 2021.

Figure 2: Ventura Natural Gas Price Forecast and Sensitivities



10. Natural Gas Transportation Costs

Gas transportation variable costs include the gas transportation charges and the Fuel Lost & Unaccounted (FL&U) for all of the pipelines the gas flows through from the Ventura Hub to the generators facility. The FL&U charge is stated as a percentage of the gas expected to be consumed by the plant, effectively increasing the gas used to operate the plant, and is at the price of gas commodity being delivered to the plant. Table 12 contains gas transportation charges for generic thermal resources.

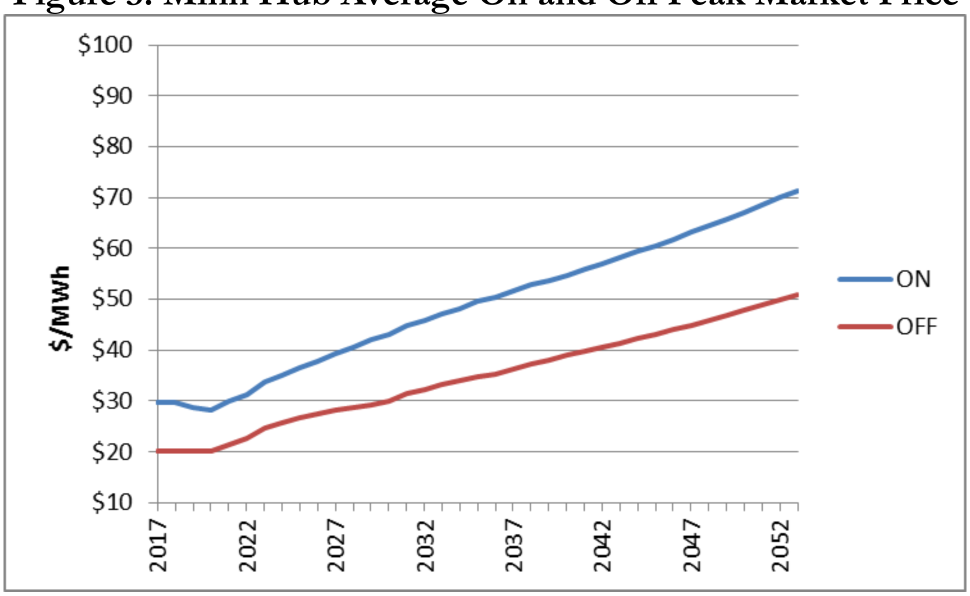
11. Natural Gas Demand Charges

Gas demand charges are fixed annual payments applied to resources to guarantee that natural gas will be available (normally called "firm gas"). Typically, firm gas is obtained to meet the needs of the winter peak as enough gas is normally available during the summer. Table 12 contains gas demand charges for generic thermal resources.

12. Electric Power Market Prices

In addition to resources that exist within the NSP System, the Company is a participant in the MISO Market. Electric power market power prices are developed from fundamentally-based forecasts from Wood Mackenzie, CERA and PIRA. Figure 3 below shows the market prices under zero cost CO_2 assumptions.

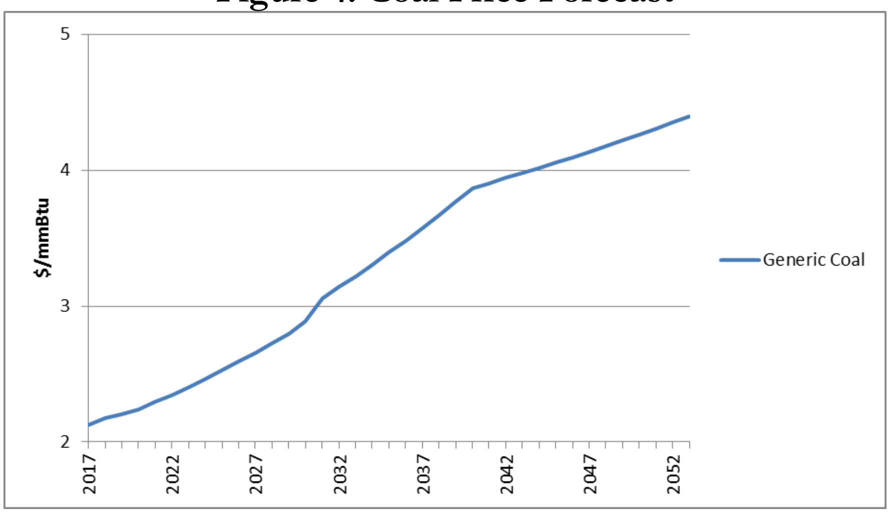
Figure 3: Minn Hub Average On and Off Peak Market Price



13. Coal Price Forecast

Coal price forecasts are developed using two major inputs: the current contract volumes and prices combined with current estimates of required spot volumes and prices. Typically coal volumes and prices are under contract on a plant by plant basis for a one to five year term with annual spot volumes filling the estimated fuel requirements of the coal plant based on recent unit dispatch. The spot coal price forecasts are developed from price forecasts provided by Wood Mackenzie, JD Energy, and John T Boyd Company, as well as price points from recent Request for Proposal (RFP) responses for coal supply. Layered on top of the coal prices are transportation charges, SO_2 costs, freeze control and dust suppressant, as required.

Figure 4: Coal Price Forecast



14. Surplus Capacity Credit

The credit is applied for all twelve months of each year and is priced at the avoided capacity cost of a generic combustion turbine.

Table 8: Surplus Capacity Credit

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
$/kW-mo	4.84	4.94	5.03	5.14	5.24	5.34	5.45	5.56	5.67	5.78

	2027	2028	2029	2030	2031	2032	2033	2034	2035
$/kW-mo	5.90	6.02	6.14	6.26	6.39	6.51	6.64	6.78	6.91

	2036	2037	2038	2039	2040	2041	2042	2043	2044
$/kW-mo	7.05	7.19	7.33	7.48	7.63	7.78	7.94	8.10	8.26

	2045	2046	2047	2048	2049	2050	2051	2052	2053
$/kW-mo	8.43	8.59	8.77	8.94	9.12	9.30	9.49	9.68	9.87

15. Transmission Delivery Costs

Generic 2x1 combined cycle (CC), generic combustion turbine (CT), generic wind and generic solar have assumed transmission delivery costs. The table below shows the transmission delivery costs on a $/kW basis. The CC and CT costs were developed based on the average of several potential sites in the Minnesota. The general site locations were investigated by Transmission Access for impacts to the transmission grid and expected resulting upgrade costs

Table 9: Transmission Delivery Costs

	$/kw	
CC	$	429
CT	$	158
Solar	$	70
Wind	$	96

16. Interconnection Costs

Estimates of interconnection costs of the generic resources were included in the capital cost estimates.

17. Effective Load Carrying Capability (ELCC) Capacity Credit for Wind Resources

Existing wind units is based on current MISO accreditation. New wind additions are given a capacity credit equal to 15.6 percent of their nameplate rating per MISO 2017/2018 Wind Capacity Report.

18. ELCC Capacity Credit for Utility Scale Solar Photovoltaic (PV) Resources

Utility scale generic solar PV additions used in modeling the alternative plans were given a capacity credit equal to 50 percent of the AC nameplate capacity. This value is the MISO proposed solar capacity credit for the 2016/2017 planning year.

19. Spinning Reserve Requirement

Spinning Reserve is the on-line reserve capacity that is synchronized to the grid to maintain system frequency stability during contingency events and unforeseen load swings. The level of spinning reserve modeled is 94 MW and is based on a 12 month rolling average of spinning reserves carried by the NSP System within MISO.

20. Emergency Energy Costs

Emergency Energy Costs were assigned in the Strategist model if there were not enough resources available to meet energy requirements. The cost was set at $500/MWh in 2014 escalating at inflation which is about $150/MWh more than an oil unit with an assumed heat rate of 15 mmBtu/MWh. Emergency energy occurs only in rare instances.

21. Wind Integration Costs

Wind integration costs were priced based upon the results of the NSP System Wind Integration Cost Study. Wind integration costs contain five components:

1. MISO Contingency Reserves
2. MISO Regulating Reserves
3. MISO Revenue Sufficiency Guarantee Charges
4. Coal Cycling Costs
5. Gas Storage Costs

The complete Wind Integration Study is included in Appendix M of the 2015 Upper Midwest Resource Plan. The results of the study as used in Strategist are shown below. The Coal Cycling Costs are zero after 2040 because the last coal unit on the Company's system in the modeling retires in 2040.

Table 10: Wind Integration Costs

	Wind Integration $/MWh		Coal Cycling $/MWh	
	Existing Resources	New Resources	Existing Resources	New Resources
2016	0.41	0.42	0.75	1.26
2017	0.42	0.43	0.77	1.28
2018	0.43	0.44	0.78	1.31
2019	0.44	0.45	0.80	1.33
2020	0.44	0.46	0.82	1.36
2021	0.45	0.46	0.83	1.39
2022	0.46	0.47	0.85	1.41
2023	0.47	0.48	0.87	1.44
2024	0.48	0.49	0.88	1.47
2025	0.49	0.50	0.90	1.50
2026	0.50	0.51	0.92	1.53
2027	0.51	0.52	0.94	1.56
2028	0.52	0.53	0.96	1.59
2029	0.53	0.54	0.98	1.62
2030	0.54	0.55	1.00	1.66
2031	0.55	0.56	1.01	1.69
2032	0.56	0.58	1.04	1.72
2033	0.58	0.59	1.06	1.76
2034	0.59	0.60	1.08	1.79
2035	0.60	0.61	1.10	1.83
2036	0.61	0.62	1.12	1.87
2037	0.62	0.63	1.14	1.90
2038	0.64	0.65	1.17	1.94
2039	0.65	0.66	1.19	1.98
2040	0.66	0.67	1.21	2.02
2041	0.67	0.69	-	-
2042	0.69	0.70	-	-
2043	0.70	0.71	-	-
2044	0.72	0.73	-	-
2045	0.73	0.74	-	-
2046	0.74	0.76	-	-
2047	0.76	0.77	-	-
2048	0.77	0.79	-	-
2049	0.79	0.80	-	-
2050	0.81	0.82	-	-
2051	0.82	0.83	-	-
2052	0.84	0.85	-	-
2053	0.86	0.87	-	-

22. Wind Congestion Costs

Wind Congestion Costs were developed by Xcel Energy Transmission Planning group from PROMOD LMP simulations for years 2020 and 2025 using the MTEP 16 database. Based on those simulations, we included congestion cost of $2.71 per MWh in 2020, escalating at 2% thereafter, for all new wind including the 300MW Dakota Range project.

Table 11: Wind Congestion Costs

	Wind Congestion $/MWh	
	Existing Resources	New Resources
2017	-	-
2018	-	-
2019	-	2.66
2020	-	2.71
2021	-	2.77
2022	-	2.82
2023	-	2.88
2024	-	2.93
2025	-	2.99
2026	-	3.05
2027	-	3.11
2028	-	3.18
2029	-	3.24
2030	-	3.31
2031	-	3.37
2032	-	3.44
2033	-	3.51
2034	-	3.58
2035	-	3.65
2036	-	3.72
2037	-	3.80
2038	-	3.87
2039	-	3.95
2040	-	4.03
2041	-	4.11
2042	-	4.19
2043	-	4.28
2044	-	4.36
2045	-	4.45
2046	-	4.54
2047	-	4.63
2048	-	4.72
2049	-	4.81
2050	-	4.91
2051	-	5.01
2052	-	5.11
2053	-	5.21

23. Distributed Generation and Community Solar Gardens

The small solar inputs are based on the most recent Company forecast.

24. Assumption and Sensitivity Descriptions

The modeling uses the following assumptions and sensitivities. The Base Assumptions are combined with the Sensitivities to test the modeling results for critical variables.

Table 12: Assumption and Sensitivity Descriptions

Base Assumptions	Assumption Description
PVSC Base	All Strategist expansion plans are optimized under the PVSC Base assumption. PVSC Base includes the Regulated CO_2 Cost of $21.50 per short ton in 2022, Externality Costs, and Surplus Capacity Credit. Optimized expansion plans were completed using the PVSC Base assumption and the PVSC Base assumption combined with the following sensitivity: Preferred Plan Renewables. All Strategist outputs except the Markets Off sensitivity assume the modeling of MISO Energy Market interactions.
PVRR Base	This assumption removes Regulated CO_2 Costs, Externality Costs, and the Surplus Capacity Credit from the PVSC Base assumption. All Strategist outputs except the Markets Off sensitivity assume the modeling of MISO Energy Market interactions.
Sensitivities	**Sensitivity Description**
Markets Off	This sensitivity removes the modeling of the Company's hourly purchases and sales in the MISO Energy Market.
Low Gas Price	This sensitivity decreases the annual year-over-year percent change in natural gas prices by 50% starting in year 2021.
High Gas Price	This sensitivity increases the annual year-over-year percent change in natural gas prices by 50% starting in year 2021.
Low CO_2 Externality	This sensitivity removes the Regulated CO_2 Cost and models the Low Externality Price of CO_2 for the modeling period.
High CO_2 Externality	This sensitivity removes the Regulated CO_2 Cost and models the High Externality Price of CO_2 for the modeling period.
+5% Cap Factor	This sensitivity increases the expected capacity factor by 5% for the proposed Dakota Range project.
-5% Cap Factor	This sensitivity decreases the expected capacity factor by 5% for the proposed Dakota Range project.
Preferred Plan Renewables	This sensitivity adds 1650MW of additional utility-scale solar by 2030.

25. Owned Unit Modeled Operating Characteristics and Costs

Company owned units were modeled based upon their tested operating characteristics and historical or projected costs. Below is a list of typical operating and cost inputs for each company owned resource.

a. Retirement Date
b. Maximum Capacity
c. Current Unforced Capacity (UCAP) Ratings
d. Minimum Capacity Rating
e. Seasonal Deration
f. Heat Rate Profiles
g. Variable O&M
h. Fixed O&M

i. Maintenance Schedule
j. Forced Outage Rate
k. Emission rates for SO_2, NO_x, CO_2, Mercury and particulate matter (PM)
l. Contribution to spinning reserve
m. Fuel prices
n. Fuel delivery charges

26. Thermal Power Purchase Agreement (PPA) Operating Characteristics and Costs

PPAs are modeled based upon their tested operating characteristics and contracted costs. Below is a list of typical operating and cost inputs for each thermal PPA.

a. Contract term
b. Maximum Capacity
c. Minimum Capacity Rating
d. Seasonal Deration
e. Heat Rate Profiles
f. Energy Schedule
g. Capacity Payments
h. Energy Payments
i. Maintenance Schedule
j. Forced Outage Rate
k. Emission rates for SO_2, NO_x, CO_2, Mercury and PM
l. Contribution to spinning reserve
m. Fuel prices
n. Fuel delivery charges

27. Renewable Energy PPAs and Owned Operating Characteristics and Costs

PPAs are modeled based upon their tested operating characteristics and contracted costs. Company owned units were modeled based upon their tested operating characteristics and historical or projected costs. Below is a list of typical operating and cost inputs for each renewable energy PPA and owned unit.

a. Contract term
b. Name Plate Capacity
c. Accredited Capacity
d. Annual Energy
e. Hourly Patterns
f. Capacity and Energy Payments
g. Integration Costs

Wind hourly patterns were developed through a "Typical Wind Year" process where individual months were selected from the years 2014-2016 to develop a typical year. Actual generation data from the selected months were used to develop the profiles for each wind farm. For farms where generation data was not complete or not available, data from nearby similar farms were used.

Solar hourly patterns were taken from the Fall 2013 and updated to reflect the ELCC as stated above. The fixed panel pattern is an average of the four orientations and three years (2008-2010) of data and single-axis tracking pattern is an average of three years of data.

28. Generic Assumptions

Generic resources were modeled based upon their expected operating characteristics and projected costs. Below is a list of typical operating and cost inputs for each generic resource.

Thermal

a. Retirement Date
b. Maximum Capacity
c. UCAP Ratings
d. Minimum Capacity Rating
e. Seasonal Deration
f. Heat Rate Profiles
g. Variable O&M
h. Fixed O&M
i. Maintenance Schedule
j. Forced Outage Rate
k. Emission rates for SO_2, NO_x, CO_2, Mercury and PM
l. Contribution to spinning reserve
m. Fuel prices
n. Fuel delivery charges

Renewable

a. Contract term
b. Name Plate Capacity
c. Accredited Capacity
d. Annual Energy
e. Hourly Patterns
f. Capacity and Energy Payments

g. Integration Costs

Tables 13-14 below show the assumptions for the generic thermal and renewable resources.

Table 13: Thermal Generic Information (Costs in 2016 Dollars)

Resource	Coal	Coal w/ Seq	2x1 CC	1x1 CC	CT	Small CT	Biomass
Nameplate Capacity (MW)	511	511	778.3	291.1	229.9	103.4	50
Summer Peak Capacity with Ducts (MW)	NA	NA	766.3	NA	NA	NA	NA
Summer Peak Capacity without Ducts (MW	485	485	649.8	290.2	226.1	100.8	50
Cooling Type	Dry	Dry	Dry	Dry	NA	Wet	Wet
Capital Cost ($/kw)	3,758	5,487	963	1,212	626	1,572	4,731
Electric Transmission Delivery ($/kw)	NA	NA	429	NA	158	NA	NA
Gas Demand ($/kw-yr)	0	0	8.96	11.98	0	0	0
Book life	30	30	40	40	30	30	30
Fixed O&M Cost ($000/yr)	16,973	25,546	7,813	4,299	614	886	5,382
Variable O&M Cost ($/MWh)	2.92	11.00	3.20	1.82	2.36	1.88	4.88
Ongoing Capital Expenditures ($/kw-yr)	9.96	24.31	4.50	4.97	6.11	1.93	14.67
Heat Rate with Duct Firing (btu/kWh)	NA	NA	7725	NA	NA	NA	NA
Heat Rate 100% Loading (btu/kWh)	9,156	12,096	6,822	7,830	9,942	8,867	14,421
Heat Rate 75% Loading (btu/kWh)	9,190	12,565	6,905	8,010	11,048	9,688	14,580
Heat Rate 50% Loading (btu/kWh)	9,710	13,600	6,943	8,583	14,601	11,161	15,570
Heat Rate 25% Loading (btu/kWh)	11,245	17,140	7,583	9,798	NA	15,067	18,650
Forced Outage Rate	6%	7%	3%	3%	3%	2%	4%
Maintenance (weeks/year)	2	5	5	4	2	2	7
CO2 Emissions (lbs/MMBtu)	216	9	118	118	118	118	211
SO2 Emissions (lbs/MWh)	0.447	0.371	0.005	0.005	0.007	0.007	0.577
NOx Emissions (lbs/MWh)	0.45	0.62	0.06	0.05	0.30	0.08	1.01
PM10 Emissions (lbs/MWh)	0.14	0.14	0.01	0.01	0.01	0.01	0.43
Mercury Emissions (lbs/Million MWh)	0.00007	0.00010	0.00000	0.00000	0.00000	0.00000	0.00017

Table 14: Renewable Generic ECC Costs - $/MWh

Year	30% ITC Solar	10% ITC Solar
2020	44	
2021	45	
2022	45	
2023	46	
2024	47	
2025	48	56
2026	49	57
2027	50	58
2028	51	60
2029	52	61
2030	53	62
2031	54	63
2032	55	64
2033	56	66
2034	58	67
2035	59	68
2036	60	70
2037	61	71
2038	62	73
2039	64	74
2040	65	76
2041	66	77
2042	67	79
2043	69	80
2044	70	82
2045		83
2046		85
2047		87
2048		89
2049		90

II. Strategist Modeling Outputs

1. Annual Net Costs and Savings

The PVRR Base annual costs and savings for the proposed Dakota Range project are in Table 1.

Table 1: Annual PVRR Net Costs (Savings) in $millions

Annual Net Costs (Savings) of Dakota Range Project, $M

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
PVRR Base	0	(1)	(0)	1	1	9	6	3	3	(5)

	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
PVRR Base	(32)	(34)	(49)	(39)	(37)	(42)	(57)	(63)	27	25

	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046
PVRR Base	1	(5)	(6)	(28)	(36)	(17)	(14)	(131)	(39)	(18)

2. Expansion Plans

The Reference Case is represented as Table 2 which includes the recently approved 1550MW wind portfolio. The expansion plan with the proposed 300MW Dakota Range wind project is shown as Table 3. Dakota Range is in year 2021, and there are no other wind or utility-scale solar additions after 2021. The 300MW Dakota Range wind project under the Preferred Plan Renewables sensitivity is represented as Table 4 which includes 1650MW of new utility-scale solar by 2030.

Table 2: Reference Case Expansion Plan

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Large Solar	262	-	-	-	-	-	-	-	-	-	-	-	-	-
Generic Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind Projects	-	-	1,150	400	-	-	-	-	-	-	-	-	-	-
CT	-	-	232	-	-	-	-	-	920	690	460	230	230	-
CC	-	-	345	-	-	-	-	-	-	-	-	-	-	-
Sherco CC	-	-	-	-	-	-	-	-	-	-	786	-	-	-

	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Large Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Generic Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind Projects	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT	230	-	-	-	-	230	230	-	230	230	-	-	-	-
CC	778	778	-	778	778	-	-	778	-	-	778	-	-	778
Sherco CC	-	-	-	-	-	-	-	-	-	-	-	-	-	-

	2045	2046	2047	2048	2049	2050	2051	2052	2053	Total
Large Solar	-	-	-	-	-	-	-	-	-	262
Generic Wind	-	-	-	-	-	-	-	-	-	-
Wind Projects	-	-	-	-	-	-	-	-	-	1,550
CT	-	-	-	-	-	-	-	-	-	3,912
CC	-	-	-	778	778	-	-	-	-	7,347
Sherco CC	-	-	-	-	-	-	-	-	-	786

Table 3: Dakota Range Expansion Plan

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Large Solar	262	-	-	-	-	-	-	-	-	-	-	-	-	-
Generic Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind Projects	-	-	1,150	400	300	-	-	-	-	-	-	-	-	-
CT	-	-	232	-	-	-	-	-	920	690	230	460	-	230
CC	-	-	345	-	-	-	-	-	-	-	-	-	-	-
Sherco CC	-	-	-	-	-	-	-	-	-	-	786	-	-	-

	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Large Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Generic Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind Projects	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT	230	460	-	-	-	-	-	-	230	-	-	230	-	-
CC	778	-	-	778	1,556	-	-	778	-	-	778	-	-	-
Sherco CC	-	-	-	-	-	-	-	-	-	-	-	-	-	-

	2045	2046	2047	2048	2049	2050	2051	2052	2053	Total
Large Solar	-	-	-	-	-	-	-	-	-	262
Generic Wind	-	-	-	-	-	-	-	-	-	-
Wind Projects	-	-	-	-	-	-	-	-	-	1,850
CT	-	-	-	-	-	-	-	-	-	3,912
CC	778	-	-	778	778	-	-	-	-	7,347
Sherco CC	-	-	-	-	-	-	-	-	-	786

Table 4: Dakota Range Expansion Plan with Preferred Plan Renewables

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Large Solar	262	-	-	-	-	400	200	300	200	150	-	400	-	-
Generic Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind Projects	-	-	1,150	400	300	-	-	-	-	-	-	-	-	-
CT	-	-	232	-	-	-	-	-	230	690	230	230	230	-
CC	-	-	345	-	-	-	-	-	-	-	-	-	-	-
Sherco CC	-	-	-	-	-	-	-	-	-	-	786	-	-	-

	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Large Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Generic Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind Projects	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT	920	-	-	-	230	230	-	-	230	230	-	-	230	-
CC	-	778	-	778	778	-	-	778	-	-	778	-	-	-
Sherco CC	-	-	-	-	-	-	-	-	-	-	-	-	-	-

	2045	2046	2047	2048	2049	2050	2051	2052	2053	Total
Large Solar	-	-	-	-	-	-	-	-	-	1,912
Generic Wind	-	-	-	-	-	-	-	-	-	-
Wind Projects	-	-	-	-	-	-	-	-	-	1,850
CT	-	-	-	-	-	230	230	-	230	4,602
CC	778	-	-	778	778	-	-	-	-	6,569
Sherco CC	-	-	-	-	-	-	-	-	-	786